GEO-SEQ Project
Quarterly Status and Cost Report
December 1, 2002–February 28, 2003

Project Overview

The purpose of the GEO-SEQ Project is to establish a public-private R&D partnership that will:

- Lower the cost of geologic sequestration by: (1) developing innovative optimization methods for sequestration technologies with collateral economic benefits, such as enhanced oil recovery (EOR), enhanced gas recovery (EGR), and enhanced coalbed methane production; and (2) understanding and optimizing trade-offs between CO_2 separation and capture costs, compression and transportation costs, and geologic sequestration alternatives.
- Lower the risk of geologic sequestration by: (1) providing the information needed to select sites for safe and effective sequestration; (2) increasing confidence in the effectiveness and safety of sequestration by identifying and demonstrating cost-effective monitoring technologies; and (3) improving performance-assessment methods to predict and verify that long-term sequestration practices are safe, effective, and do not introduce any unintended environmental impact.
- Decrease the time to implementation by: (1) pursuing early opportunities for pilot tests with our private-sector partners and (2) gaining public acceptance.

In May 2000, a project kickoff meeting was held at Ernest Orlando Lawrence Berkeley National Laboratory (Berkeley Lab) to plan the technical work to be carried out, starting with FY00 funding allocations. Since then, work has been performed on four tasks: (A) development of sequestration co-optimization methods for EOR, depleted gas reservoirs, and brine formations; (B) evaluation and demonstration of monitoring technologies for verification, optimization, and safety; (C) enhancement and comparison of computer-simulation models for predicting, assessing, and optimizing geologic sequestration in brine, oil, and gas, as well as coalbed methane formations; and (D) improvement of the methodology and information available for capacity assessment of sequestration sites. Recently, a new task in support of the Frio Brine Pilot Project (E) has been added.

This Quarter's Highlights

- The GEO-SEQ Advisory Council met on January 22–23, 2003, at Berkeley Lab. A summary of the meeting and comments by the panel of experts was sent to everyone associated with the Project.
- Co-optimization simulation studies showed that storage of CO_2 can be increased with little or no loss in oil production—through active control of injection and production conditions while injecting pure CO_2.
- The first reactive transport experiment intended to lend credibility to model calculations and simulations was completed.
- Gas and isotope compositions of some of the wells sampled at Lost Hills, California, in October 2002 indicate a slight-to-modest dilution of injection CO_2 by indigenous reservoir gas.
- Several comparisons of numerical simulation results from coalbed greenhouse gas sequestration sites were completed.
- The report on the code intercomparison of reservoir simulation models for oil, gas, and brine formulations was finalized.
- Modeling studies of the post-injection period for the Frio pilot experiment were extended from one year to 100 years.
- A basin-scale conceptual model of geologic complexity for the Frio site was developed.
- A spreadsheet for the CO_2 injection test planned as part of the Frio Brine Pilot Project was drafted.
- The Bureau of Economic Geology (BEG) completed permit preparation for the Frio Brine Pilot Project injection test. The GEO-SEQ team developed some of the documents and data that were needed.

Papers Presented, Submitted, Accepted, or Published during This Quarter

Cole, D.R., J. Horita, M.C. van Soest, B.M. Kennedy, and M.F. Morea, Gas chemistry and isotope monitoring during the Lost Hills, California, CO_2 injection test. Paper accepted for presentation at NETL's Second National Conference on Carbon Sequestration (May 5–8, 2003, Alexandria, VA).

Doughty, C., S.M. Benson, and K. Pruess, Development of a well-testing program for a CO_2 sequestration pilot in a brine formation. Paper accepted for presentation at NETL's Second National Conference on Carbon Sequestration (May 5-8, 2003, Alexandria, VA).

Fisher, L.S., D.R. Cole, J.G. Blencoe, G.R. Moline, J.C. Parker, and T.J. Phelps, High-pressure flow-through column for assessing subsurface carbon sequestration. Paper accepted for presentation at NETL's Second National Conference on Carbon Sequestration (May 5-8, 2003, Alexandria, VA).

Hovorka, S.D., and P.R. Knox, What does a permit look like for disposal of carbon dioxide waste plus enhanced recovery of oil and gas? Paper accepted for presentation at 2003 Underground Injection Symposium (May 7, 2003, Austin, TX)

Hovorka, S.D., P.R. Knox, M.H. Holtz, J.S.Yeh, K. Fouad, and S. Sakurai, Taping the potential for large volume sequestration—Update on the Frio Brine Pilot Project. Paper accepted for presentation at NETL's Second National Conference on Carbon Sequestration (May 5-8, 2003, Alexandria, VA).

Holtz, M.H., Optimization of CO_2 sequestered as a residual phase in brine-saturated formations. Paper accepted for presentation at NETL's Second National Conference on Carbon Sequestration (May 5-8, 2003, Alexandria, VA).

Johnson, J.W., J.J. Nitao, R.L. Newmark, B.A. Kirkendall, G.J. Nimz, and K.G. Knauss. Geologic approaches to carbon management: CO_2-flood EOR and saline aquifer storage. Paper accepted for presentation at the 28th International Conference on Coal Utilization & Fuel Systems (March 9-13, 2003, Clearwater, FL).

Johnson, J.W., J.J. Nitao, and J.P. Morris. Reactive transport modeling of long-term cap rock integrity during CO_2 injection for EOR or saline-aquifer storage. Paper accepted for presentation at NETL's Second National Conference on Carbon Sequestration (May 5-8, 2003, Alexandria, VA).

Knauss, K.G., J.W. Johnson and C.I. Steefel. Evaluation of the impact of CO_2, co-contaminant, aqueous fluid, and reservoir rock interactions on the geologic sequestration of CO_2. Paper accepted for presentation at the 28th International Conference on Coal Utilization & Fuel Systems (March 9–13, 2003, Clearwater, Florida).

Knauss, K.G., J.W. Johnson, and C.I. Steefel. CO_2 sequestration in the Frio FM TX: Evaluation of the impact of CO_2, co-contaminant gas, aqueous fluid, and reservoir rock interactions. Paper accepted for presentation at NETL's Second National Conference on Carbon Sequestration (May 5–8, 2003, Alexandria, Virginia).

Law, D.H-S., GEO-SEQ project, numerical model comparison study for greenhouse sequestration in coalbeds—An update. Paper accepted for presentation at the Coal-Seq II Forum (March 6–7, 2003, Washington, D.C.)

Law, D.H.-S., L.G.H. (Bert) van der Meer and W.D.(Bill) Gunter, Comparison simulators for greenhouse gas sequestration in coalbeds, Part III: More complex problems. Paper accepted for presentation at NETL's Second National Conference on Carbon Sequestration (May 5–8, 2003, Alexandria, VA).

Oldenburg, C.M., Carbon dioxide as cushion gas for natural gas storage. *Energy&Fuels*, *17*(1), 240–246, 2003.

Oldenburg, C.M., S.H. Stevens, and S.M. Benson, Economic feasibility of carbon sequestration with enhanced gas recovery (CSEGR), Paper submitted to *Energy*, LBNL-49762, 2003.

Oldenburg, C.M., S.W. Webb, K. Pruess, and G.J. Moridis, Mixing of stably stratified gases in subsurface reservoirs: A comparison of diffusion models. Paper submitted to *Transport in Porous Media*, LBNL-51545, 2003.

Pruess, K. and J. García, Solutions of test problems for disposal of CO_2 in saline aquifers. Lawrence Berkeley National Laboratory Report LBNL-51812, December 2002.

Pruess, K., J. García, T. Kovscek, C. Oldenburg, J. Rutqvist, C. Steefel and T. Xu, Intercomparison of numerical simulation codes for geologic disposal of CO_2. Lawrence Berkeley National Laboratory Report LBNL-51813, December 2002.

Pruess, K., J. García, T. Kovscek, C. Oldenburg, J. Rutqvist, C. Steefel, and T. Xu. Code intercomparison builds confidence in numerical simulation models for geologic disposal of CO_2. Paper submitted to *Energy*, LBNL-52211, 2003.

Pruess, K., T. Xu, J. Apps and J. García, Numerical modeling of aquifer disposal of CO_2. *Society of Petroleum Engineers Journal*, 49-60, LBNL-47135, 2003.

Rau. G.H., K.G. Knauss and K. Caldera. Capturing and sequestering flue-gas CO_2 using a wet limestone scrubber. Paper accepted for presentation at NETL's Second National Conference on Carbon Sequestration (May 5–8, 2003, Alexandria, VA).

Task Summaries

Task A: Develop Sequestration Co-Optimization Methods

Subtask A-1: Co-Optimization of Carbon Sequestration, EOR, and EGR from Oil Reservoirs

Goals

To assess the possibilities for co-optimization of CO_2 sequestration and enhanced oil recovery (EOR), and to develop techniques for selecting the optimum gas composition for injection. Results will lay the groundwork necessary for rapidly evaluating the performance of candidate sequestration sites, as well as monitoring the performance of CO_2 EOR.

Previous Main Achievements

- Screening criteria for selection of oil reservoirs that would co-optimize EOR and maximize CO_2 storage in a reservoir have been generated.
- We have thoroughly studied a streamline-based proxy for full reservoir simulation that allows rapid selection of a representative subset of stochastically generated reservoir models that encompass uncertainty with respect to true reservoir geology.

Accomplishments This Quarter

- Reservoir simulation studies of co-optimization have shown that storage of CO_2 can be increased, with little or no loss in oil production, through active control of injection and production conditions while injecting pure CO_2.

Progress This Quarter

Work continued on considering, via reservoir simulation, various reservoir development scenarios to understand better reservoir development and production techniques that maximize the simultaneous production of oil and storage of CO_2. These scenarios are evaluated using a synthetic, three-dimensional, compositional reservoir model that includes a description of uncertainty in the permeability distribution.

This reservoir model was developed in previous quarters. We found that pure CO_2 is not miscible in this crude oil at reservoir pressure. Scenarios have used pure CO_2 as an immiscible injection gas and a solvent gas composed of about 2/3 CO_2 (by mole). We have examined simulations of water-alternating-gas (WAG) drive mode with various immiscible and miscible gas slug sizes, gas injection early in production life versus late in reservoir life, gas injection following waterflooding, and gas-controlled production.

From an oil-recovery standpoint, recovery is enhanced to an extent significant enough to warrant the injection of a miscible solvent. This statement is true across all scenarios.

The scenario requires some further comment. A production well is shut in if the producing gas-oil ratio (GOR) reaches a prespecified high level. The well is opened again when the well pressure approaches the original reservoir pressure. The well is shut in again when/if the producing GOR again climbs. Each time the well is turned back on the GOR constraint is incrementally increased (100 to 250 SCF/STB) to assure that the well remains on for some time. The main result of this constraint is to limit the amount of produced gas and to increase the volume of reservoir contacted by gas. Shutting in a well changes the pattern of gas movement compared to the WAG cases. Oil production and CO_2 storage are increased by 12 to 20% with this technique.

All of the scenarios that were simulated highlight the mobility control problems associated with gas injection. Large mobility ratios lead to premature breakthrough of CO_2 at production wells and incomplete sweep of reservoir volume. Aqueous foams have the ability to profoundly alter the mobility of injected gas. To this end, we are currently conducting experiments to measure the trapping of CO_2 by foam. A dual-gas tracer method is being employed to measure the trapped gas fraction. Additionally, X-ray Computer-aided Tomography (CT) scanning can monitor the progress of CO_2 injection into sandstone.

Work Next Quarter

Streamline-based proxy results for full reservoir simulations that were developed in previous quarters are being written up for submission to a journal.

Simulation work for co-optimization of oil recovery and CO_2 storage will continue. We will pursue the gas-controlled production scenario fully. Additionally, most results to date have been obtained from a single realization of reservoir permeability. We will conduct further simulations to show that the results obtained do not vary from one realization of geology to the next. That is, we will show that production scenarios leading to the best oil recovery and gas storage for a given realization of geology show good results throughout the suite of equi-probable realizations.

Experiments involving CO_2 trapping by foam will continue. The *in situ* distribution of CO_2 will be imaged using x-ray computed tomography.

Subtask A-2: Feasibility Assessment of Carbon Sequestration with Enhanced Gas Recovery (CSEGR) in Depleted Gas Reservoirs

Goals

To assess the feasibility of injecting CO_2 into depleted natural gas reservoirs for sequestering carbon dioxide (CO_2) and enhancing methane (CH_4) recovery. Investigation will include assessments of (1) CO_2 and CH_4 flow and transport processes, (2) injection strategies that retard mixing, (3) novel approaches to inhibit mixing, and (4) identification of candidate sites for a pilot study.

Previous Main Achievements

- On the basis of numerical-simulation studies, the proof-of-concept for CO_2 storage with enhanced gas recovery (CSEGR) was demonstrated.
- It was found that transport in high-permeability gas reservoir can be adequately simulated using the Advective Diffusive Model (ADM), but that the Dusty Gas Model (DGM) is more appropriate for lower permeability units.

Accomplishments This Quarter

- Investigators carried out additional CSEGR simulations for the case considered in the economic feasibility study described in the Oldenburg, Stevens, and Benson paper presented in Kyoto last October.

Progress This Quarter

Additional numerical simulations were performed to closely match the physical properties of the reservoir used in the economic feasibility case study presented at the October 2002 Kyoto meeting. The results of these simulations (**Figure 1)** were added to those of the Kyoto paper and submitted to the journal *Energy*.

Curt Oldenburg contacted Chris Fling (Samson Resources) and Michael Moore (Falcon Environmental Resources) regarding potential CSEGR pilot study locations. He also worked with Paul Knox to arrange a contact by the Texas BEG to GTI.

Oldenburg also began training Dr. Dorothee Rebscher, a visiting scientist from the University of Bonn (Germany) in the use of TOUGH2 for simulating the behavior of a natural gas field in Germany as CO_2 is injected (i.e., CSEGR simulations).

A mini-proposal for CO_2 gas monitoring at the Frio Brine Pilot Project (Task E) was prepared.

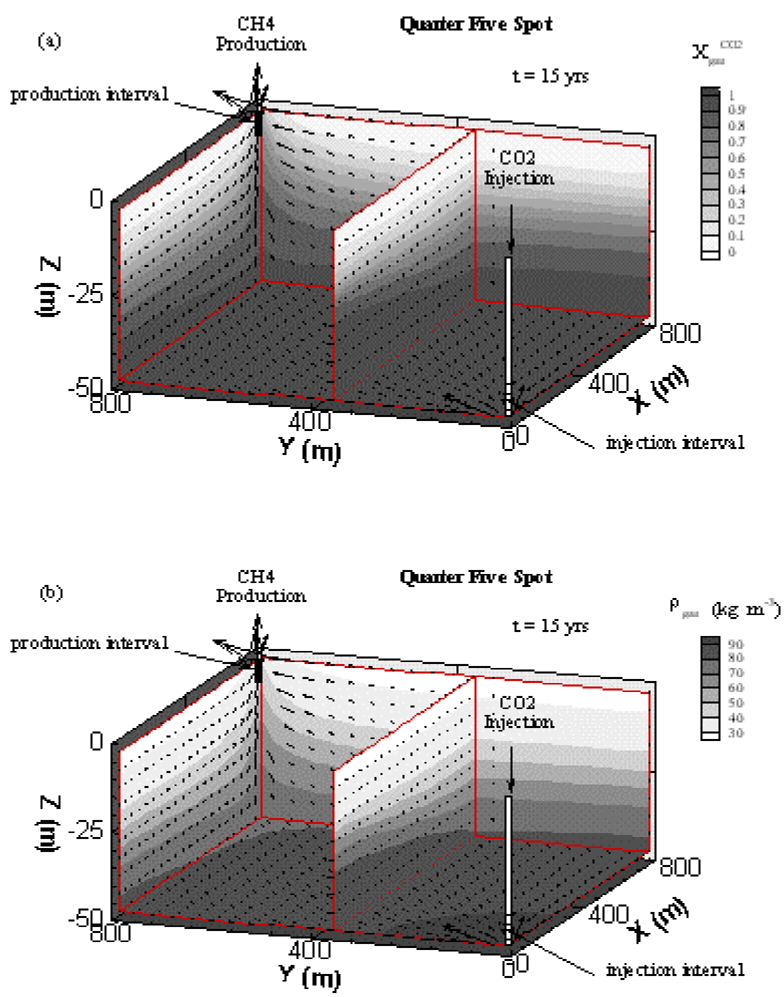

Figure 1. (a) CO_2 mass fraction in the gas and (b) gas density (kg/m^3) after 15 years of injection into the lower part of the reservoir

Work Next Quarter

- Finalize the economic feasibility paper based on reviewers' comments from the journal *Energy*.
- Continue working on the improvement of the CH_4-CO_2-H_2O model.
- Continue, in collaboration with our industry contact, the identification of potential CSEGR pilot sites.

Subtask A-3: Evaluation of the Impact of CO_2 Aqueous Fluid and Reservoir Rock Interactions on the Geologic Sequestration of CO_2, with Special Emphasis on Economic Implications.

Goals

To evaluate the impact on geologic sequestration of injecting an impure CO_2 waste stream into the storage formation. By reducing the costs of front-end processes, the overall costs of sequestration could be dramatically lowered. One approach is to sequester impure CO_2 waste streams that are less expensive or require less energy than separating pure CO_2 from the flue gas.

Previous Main Achievements

- Potential reaction products have been determined, based upon reaction-progress chemical thermodynamic/kinetic calculations for typical sandstone and carbonate reservoirs into which an impure CO_2 waste stream is injected.
- Reactive transport simulations have been completed for a plug-flow reactor run using the Frio Formation core material acquired in support of Task E. Additional simulations were performed as part of the Frio Brine Pilot Project planning efforts (Task E).
- The plug-flow reactor was upgraded by installing new pump-operating software

Accomplishments This Quarter

- We designed and initiated our first reactive transport experiment, intended to lend credibility to the model calculations and simulations done to date. This run, in our modified flow reactor, is intended to test the reactive transport simulator's capability to accurately model silicate mineral (clay) precipitation.

Progress This Quarter

The process of evaluating the impact of waste stream CO_2 and contaminants (e.g., SO_2, NO_2, and H_2S), on injectivity and sequestration performance continued during this quarter.

Our prior experience benchmarking reactive transport simulators against ideal reactive transport experiments (e.g., Johnson et al., 1998) suggests that our simulators handle dissolution of the more common rock-forming minerals reasonably well. However, these simulators have not been rigorously evaluated in terms of accurately modeling mineral growth. This is a serious shortcoming.

In the first of a planned series of plug-flow reactor (PFR) experiments specifically designed to address this problem, we have used a simulator (CRUNCH) to design an experiment that should produce a measurable amount of clay-mineral (kaolinite) reaction product under conditions directly relevant to geologic sequestration of CO_2. This issue is of some practical importance, because in the acidic conditions near the injection well, the dissolution of silicate minerals could result in the growth of clay minerals, which in turn could decrease injectivity.

In both the experiment and simulation, we used the composition of a Frio sand sample taken from well Merisol WDW No. 319. The starting mineralogy in the simulation consisted of a mix of quartz, K-feldspar, plagioclase (compositionally An60 with thermodynamic properties calculated as an ideal mixture of end-member albite and anorthite), pyrite, muscovite (as a proxy for illite), kaolinite, clinochlore (as the Mg end-member chlorite) and calcite as the cement mineral. As a proxy for the formation fluid, we used a 0.7m NaCl solution, approximately equivalent to seawater in ionic strength. In the simulation and in the experiment, this fluid was first equilibrated with 20b CO_2 gas pressure in an external Ti bomb (see **Figure 2**) heated to run temperature (150°C—explained below). These conditions served to prime the precision Quizix pump, which further increased the fluid pressure to 80 b before letting the fluid flow through the core contained in the tube furnace inside the PFR apparatus. In the experiment, quantitative samples of the effluent gas and liquid were collected frequently in gas-tight syringes and analyzed for Ca, Mg, Na, K, Cl, Fe, CO_2, Al, Si, and pH. In the simulation, we can, of course, calculate not only the composition of the effluent exiting the core (i.e., the samples collected), but also the compositions of fluids, gases, and solids throughout the core in both space and time.

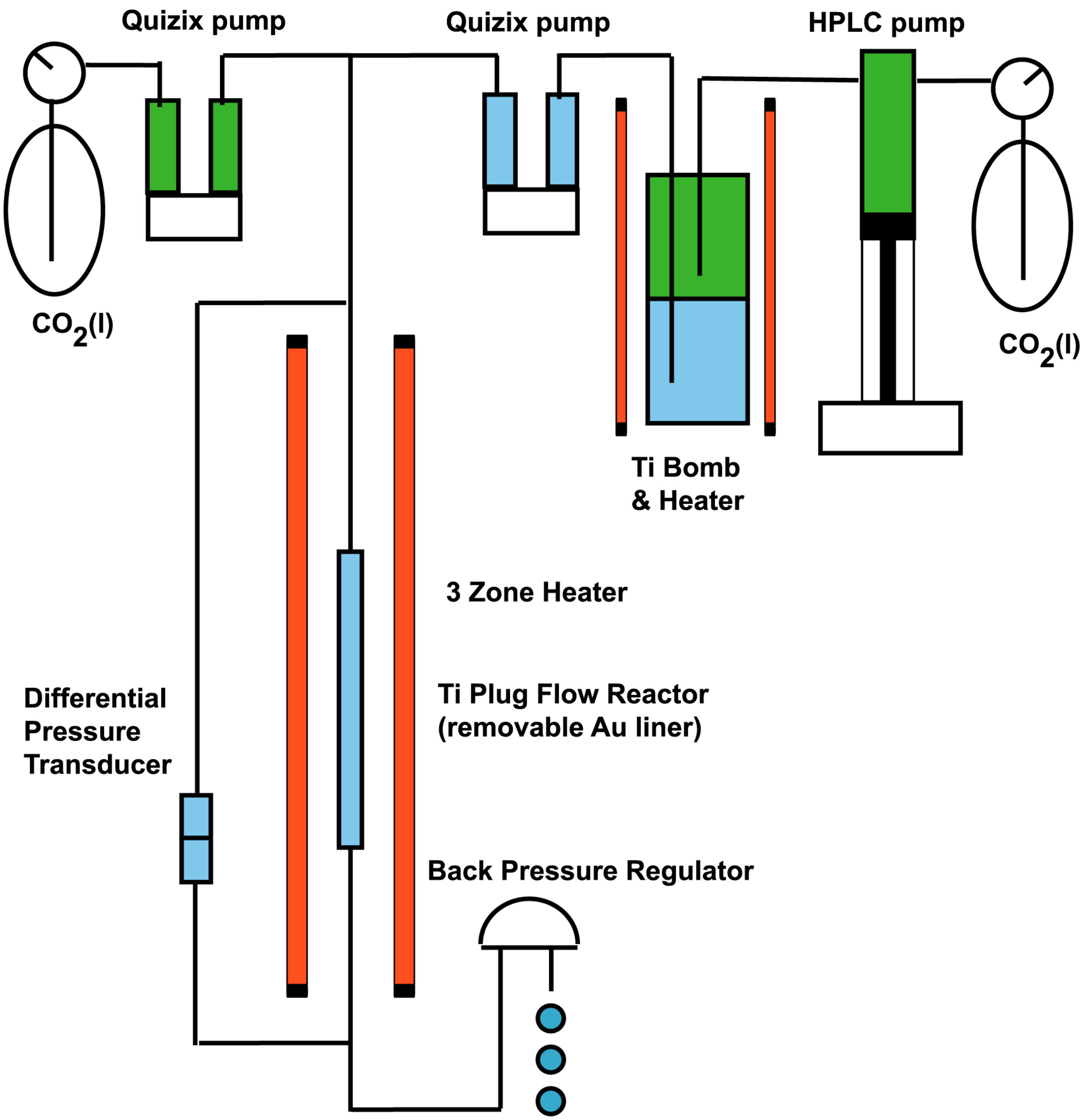

Figure 2. Plug-Flow Reactor (PFR) schematic

Internal components of the PFR system are shown in **Figure 3**. The Au liner inside the Ti column reactor allows us to subsample the reacted core, as seen in the 1 cm subsamples inside the ziplock bags. During a postmortem, these bags can be analyzed for run products using a variety of techniques The system as a whole is shown in **Figure 4**, with the exception of the CO_2 tank, which is just outside the field of view to the left. In this experiment, we did not inject a separate CO_2 phase into the core, so we did not use the second Quizix pump shown to the left side of **Figure 2**.

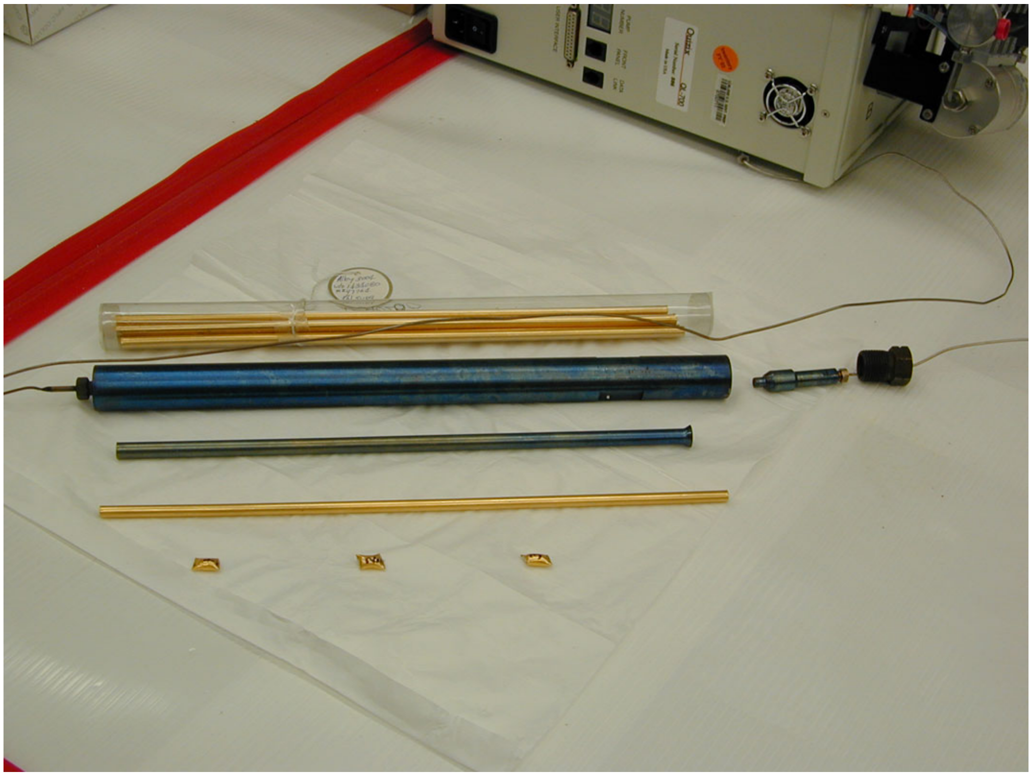

Figure 3. PFR system's gold liner and titanium pressure vessel

Figure 4. PFR system

Because we use an ideal physical model (the PFR), we could set the simulation up as a very simple 1D calculation, which approximates a single streamline between the injection well and the observation or production well. Because the incoming fluid is acidic (as a result of the high CO_2 pressure [pH 3.7]), we use full kinetic rate laws for each mineral, accounting for acid catalysis. Preliminary equilibrium modeling required to speciate the model water at run initialization suggested that possible secondary minerals included chalcedony, dawsonite, magnesite, and siderite. These minerals could precipitate, as well as any of the primary minerals, and kinetic rate laws also governed precipitation.

Our goal was to try to maximize the likelihood of producing quantifiable amounts of the expected secondary mineral kaolinite. Using the simulator as a test bed, we determined that by using a flow rate of 100 g/d for 30 days and a temperature of 150°C, we should produce enough new kaolinite distributed throughout the core so as to be easily quantified during the postmortem. These conditions should also produce easily measurable compositional signals in the effluent. The reason for using a higher temperature than expected in a CO_2 sequestration reservoir was to try to accommodate any kinetic inhibition to mineral growth owing to nucleation effects, etc. Our goal is not only to match the chemistry of the effluent through time, but also to match the distribution and composition of minerals throughout space at the end of the experiment.

As an example of the results of our *a priori* simulations, we show in **Figure 5** the calculated composition of the effluent as a function of time and the distribution of several mineral phases in space at the end of the run. These simulation results should match the samples that will be acquired during the experiment. Note that in these *a priori* simulations, we have made a number of assumptions that may or may not be borne out by the experimental results. For example, we have assumed that the active mineral-specific surface areas are accurately represented by a geometric approximation based on grain size. We have also assumed that no kinetic inhibition exists to the growth of any secondary minerals, and so forth. The accuracy of these assumptions and the correctness of the model itself are precisely what we will test using the results from this PFR experiment.

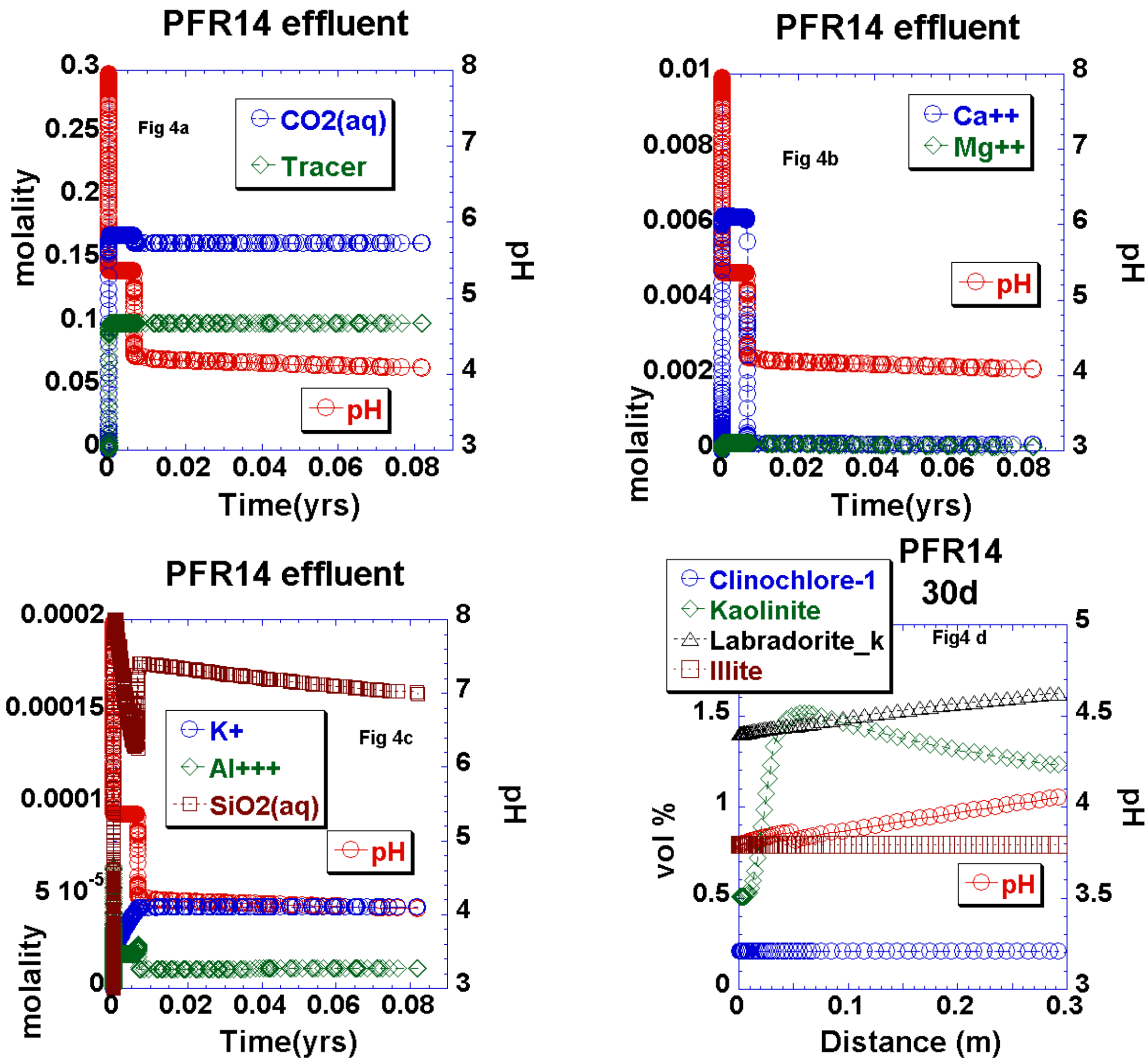

Figure 5. Composition of effluent throughout the experiment (a, b, c) and distribution of minerals at conclusion of experiment (d) PFR14. See text for details.

This experiment was successfully completed on 02/27/03 after running for 30 days. Up to that point, we had only received analytical chemistry results for the first half of the experiment. A complete analysis and interpretation of the results will have to wait until the entire solid and fluid analyses are complete. (This will occur within a few weeks following termination of the run.) However, based on the results for the first half of the experiment, either the geometric surface-area approximation underestimates the specific surface areas or, under these experimental conditions, we are in fact only seeing the solution signal from mineral dissolution, with no mineral growth occurring. The postmortem analysis of the core will answer this question. If it should be the case that only mineral dissolution is occurring, then a second experiment at an even higher temperature (to overcome any kinetic inhibition to mineral growth) should provide a good test of mineral growth. Of course, if the postmortem of the solids confirms that only dissolution has occurred, we will use the results from this experiment to benchmark the code’s performance in accurately portraying dissolution and transport.

Work Next Quarter

We will continue investigating the impact of CO_2, as well as other contaminants (SO_2, H_2S, NO_2) in the CO_2 waste stream. Our attention will stay focused on work that may help in the design and conduct of the Frio Pilot Project. We plan to complete analysis of the recently completed reactive transport experiment (PFR14) and use the results to begin benchmarking our simulator. To our knowledge, these experiments provide the first really quantifiable tests of any simulator used to date that are directly relevant to CO_2 sequestration. (See comments on difficulties below.)

Task B: Evaluate and Demonstrate Monitoring Technologies

Subtask B-1: Sensitivity Modeling and Optimization of Geophysical Monitoring Technologies

Goals

To (1) demonstrate methodologies for, and carry out an assessment of, the effectiveness of candidate geophysical monitoring techniques; (2) provide and demonstrate a methodology for designing an optimum monitoring system; and (3) provide and demonstrate methodologies for interpreting geophysical and reservoir data to obtain high-resolution reservoir images. The Chevron CO_2 pilot at Lost Hills, California, has been used as an initial test case for developing these methodologies.

Previous Main Achievements

A methodology for site-specific selection of monitoring technologies was established and demonstrated.

Modeling studies based on well logs from the Liberty Field in south Texas showed that before CO_2 injection, seismic reflection from shale-sand interfaces decreases in amplitude with increasing depth. As CO_2 is injected at shallow depth, reflectivity sharply decreases.

Those numerical studies also indicated that even if a CO_2 wedge were seismically detected because of geometric effects, interpretation of the reflection for fluid properties would be difficult until the horizontal extent of the CO_2 zone exceeds one seismic Fresnel zone.

Results of other modeling work suggested that injection of CO_2 into the Liberty Field (South Texas) formation would produce an easily measurable streaming potential (SP) response.

Accomplishments This Quarter

A first draft spreadsheet for the CO_2 injection test planned as part of the Frio Brine Pilot Project (Task E) was developed.

Progress This Quarter

The principal investigator for this subtask (Mike Hoversten) concentrated on organizing and scheduling the field activities of the Frio Brine Pilot Project injection test scheduled for Fall 2003.

Work Next Quarter

Continue SP laboratory measurements. Laboratory measurements to date have produced unexpected results; work is continuing to understand the nature of the SP response.

Subtask B-2: Field Data Acquisition for CO_2 Monitoring Using Geophysical Methods

Goals

To demonstrate (through field testing) the applicability of single-well, crosswell, and surface-to-borehole seismic, crosswell electromagnetic (EM), and electrical-resistance tomography (ERT) methods for subsurface imaging of CO_2.

Previous Main Achievements

- The first test of the joint application of crosswell seismic and crosswell electromagnetic measurements for monitoring injected CO_2 was completed.
- A scoping study of tiltmeter methods to detect and monitor CO_2 injection as part of the Frio Brine Pilot Project (Task E) was refined.
- A time-lapse electrical-resistance tomography (ERT) casing survey was completed in the Vacuum Field New Mexico, a site where CO_2 injection is taking place.

Accomplishments and Progress This Quarter

Because of lack of funding, there are no activities to report.

Work Next Quarter

Assuming additional funding is made available:

- The use of tiltmeters during the Frio Brine Pilot Project will be assessed with respect to the actual project plans and more specific field model(s).
- A time-lapse ERT survey will be obtained in the Vacuum Field over a much larger region in which CO_2 injection has begun. Time-lapse surveys obtained in this portion of the field have the potential to capture changes resulting from the movement of CO_2, as well as to demonstrate the method using wells connected by metallic surface piping. Field data will be processed and interpreted.

Subtask B-3: Application of Natural and Introduced Tracers for Optimizing Value-Added Sequestration Technologies

Goals

To provide methods that utilize the power of natural and introduced tracers to decipher the fate and transport of CO_2 injected into the subsurface. The resulting data will be used to calibrate and validate predictive models utilized for (1) estimating CO_2 residence time, reservoir storage capacity, and storage mechanisms; (2) testing injection scenarios for process optimization; and (3) assessing the potential leakage of CO_2 from the reservoir.

Previous Main Achievements

- Laboratory isotopic-partitioning experiments and mass-balance isotopic-reaction calculations have been done to assess carbon- and oxygen-isotope changes (focused on the influence of sorption) as CO_2 reacts with potential reservoir phases.
- Detailed experiments have been conducted on perfluorocarbon tracer gas-chromatography analytical methods, reproducibility, and sensitivity as a prelude to tracer flow experiments.

Accomplishments This Quarter

- Dynamic flow system operation variables for flow and pressure were verified.
- Preliminary single PFT tracer flow experiments were performed using the Ottawa sand
- Gas and isotope compositions have been determined for wells sampled on 10/8/2002 at Lost Hills, California, which indicate a slight-to-modest dilution of injection CO_2 by indigenous reservoir gas in select wells compared to the previous sampling on 6/12/2002.

Progress This Quarter

Applied Gas Tracer Studies

Preliminary testing of single PFTs and evaluation of the dynamic flow system were conducted this quarter. Perfluoromethyl cyclopentane (PMCP) was chosen as the initial tracer for preliminary injection testing. We injected 1 mL of the 0.1μg standard through a 70°C-heated gas-tight syringe and allowed it to homogenize overnight. System evaluation indicated a source of potential tracer dilution through the condensation trap located on the system; in response, we modified the system. Additional tests were conducted using perfluorodimethyl cyclohexane (PDCH) because of its isomeric peak signatures, which are distinct from nitrogen peaks. A 10 mL headspace sample of PDCH was drawn using a gas-tight syringe heated to 70°C and injected under vacuum into the simulator for homogenization in a gas homogenization reservoir (GHR). The system was then pressurized to the selected experimental pressure of 700 psi, with an ambient temperature of 19°C. Samples were allowed to homogenize overnight to ensure thorough mixing with the nitrogen carrier gas. An equal pressure gradient was maintained both upstream and downstream of the sediment flow-column. Upstream pressure was maintained by the use of a high-performance liquid chromatography (HPLC) pump (Varian Instruments) with a built-in pressure transducer, while downstream pressures were regulated with a backpressure regulator. An experimental flow rate of 3 mL/min was established using the HPLC to direct tracers from the GHRs into the sediment flow-column through a series of valves.

A Hewlett-Packard 5890 gas chromatograph (Agilent Technologies) was used to quantify peak separation of PDCH. GC parameters included an $ALOH_2$ column (50 m length, 0.53 mm ID), split vent 51 mL/min, septum purge 2.6 mL/min, column flow 11.5 mL/min, detector temperature 250°C, and injector temperature of 90°C. Oven parameters followed a temperature ramp program, with the initial temperature set to 120°C and raised 50°C (per 40 seconds) to reach a final temperature of 170°C. Samples were retrieved every 7 minutes through a 10-inlet Valco (Houston, TX) gas-sampling valve containing a 250μL sample loop. Sample times were based upon retention times of perfluorocarbon standard curves.

Results:

The initial injection of PDCH into one of the 300 mL GHRs was 2 ng, thus 7 pg/mL of PFT was allowed to homogenize within the GHR. Upon exiting the flow-through column filled with Ottawa sand, PFT sample concentrations were determined (based upon the standard curve) to be 0.1 pg (**Figure 6**), corresponding to our predictions. The resulting concentration approached the instrument detection limit, but was approximately 10 above the baseline.

Results from our preliminary experiments on the geo-sequestration simulator have demonstrated a working system that is reproducible, sensitive to low levels of detection, and capable of distinguishing physical and geochemical parameters affecting long-term sequestration of CO_2.

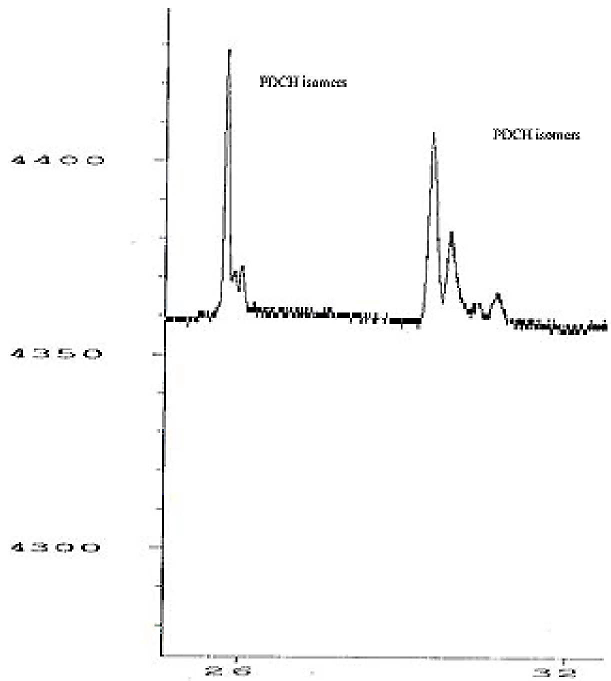

Figure 6. GC response for PDCH determined from gas sampling during preliminary PFT injections into the flow system

Gas Chemistry and Stable Isotopes

Gas compositions (CO_2, C_1-C_6, N_2, O_2) have been measured for samples obtained from Lost Hills, California, on October 8, 2002, approximately three weeks after the end of a period of modest CO_2 injection that started in early May. Isotope compositions were also measured on the CO_2 injectate, as well as CO_2 and CH_4 separated from the production gases. Gas chemistries are plotted together with results we had obtained previously from earlier samplings on CO_2-CH_4-ΣC_2-C_6 ternaries, shown in **Figure 7**.

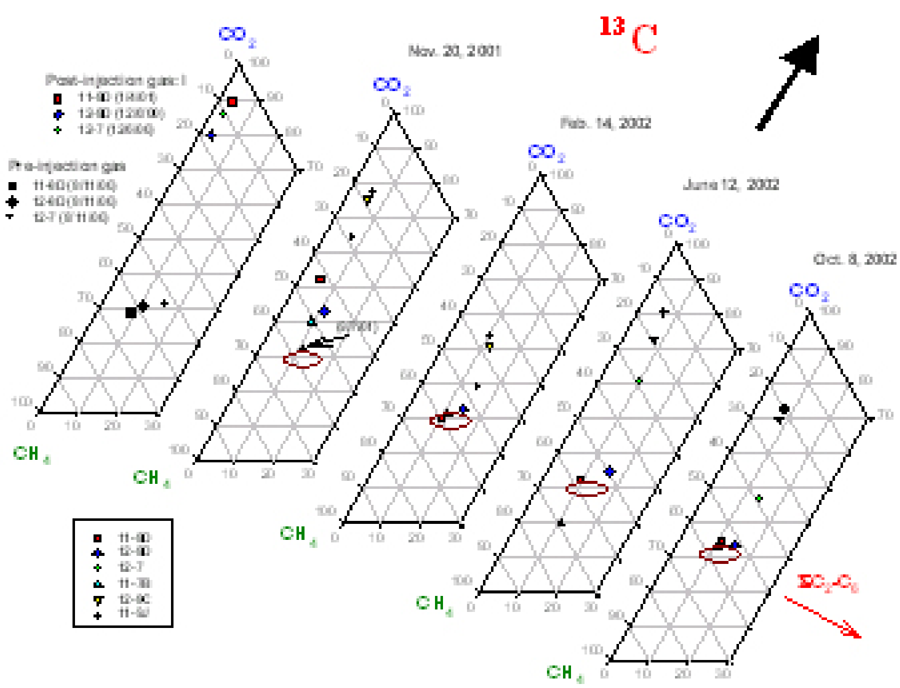

Figure 7. Lost Hills gas chemistry plotted in CO_2-CH_4-ΣC_2-C_6 ternary spaceas a function of sample date

Clearly, the contribution by injectate CO_2 has become somewhat less pronounced over time since the June 12th sampling for some wells (11-9J, 11-7B, 12-7). Gas chemistries for wells 11-8D, 12-8D and 11-7B are very close to the gas compositions determined for wells sampled prior to the initiation of the CO_2 injection test (9/19/00), which we presume represents the "baseline" reservoir chemistry. The gas chemistry for well 11-7B plots within the range of compositions thought to represent the indigenous reservoir system, but with considerably more CO_2 than it exhibited in the more CH_4-rich June sample. The reason for this shift to more CO_2 is not immediately apparent, since the CO_2 injection activity ended on September 15, 2002. Despite the fact that CO_2 injection had been stopped roughly three weeks prior to the October sampling, a significant injectate contribution still exists within three of the six wells sampled. Interestingly, these three wells are located at approximately opposite corners of the four 2.5-acre pattern—i.e., wells 11-9J and 12-8C are in the SW quadrant, and well 12-7 is located in the NE corner. The implication of this observation is being assessed in the context of both the nature of the injection (i.e., which injection wells were used and for how long) and the known fault structure in the area.

The carbon isotope compositions of CO_2 are plotted as a function of time in **Figure 8.** In general, $\delta^{13}C$ values are similar to those measured in gases sampled in June, indicating that despite the cessation of CO_2 injection, the gas and isotopic chemistry has remained relatively constant. The one notable exception is the obvious decrease in CO_2 content and associated increase in $\delta^{13}C$ for well 12-7 compared to the June sampling. The oxygen isotope compositions (**Figure 9)** have remained relatively constant since the November 20, 2001, sampling, with values varying between 36 and 40 per mil. This range would be expected if the CO_2 equilibrated with reservoir brines at temperatures between 40 and 60°C.

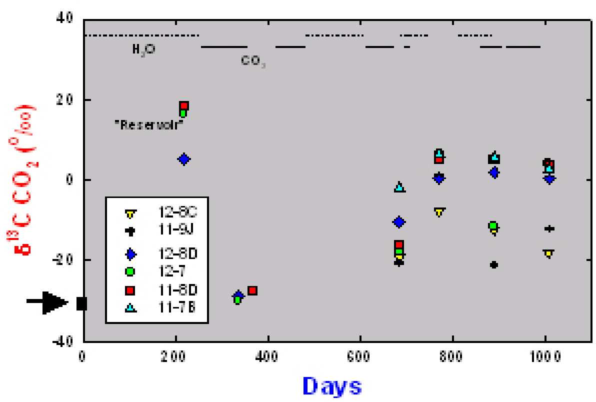

Figure 8. Carbon isotope compositions of CO_2 plotted against sample time for the Lost Hills system. Injectate CO_2 has a $\delta^{13}C$ value of roughly –31 per mil.

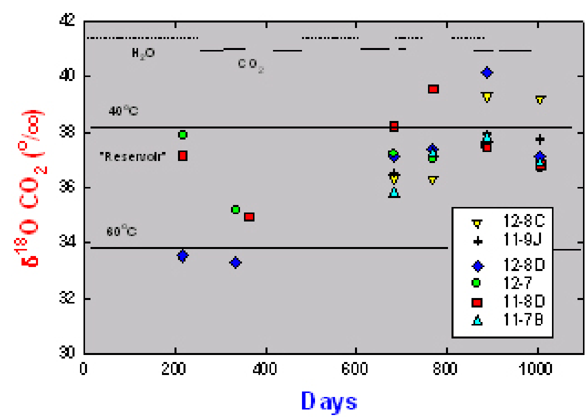

Figure 9. Oxygen isotope compositions of CO_2 plotted against sample time for the Lost Hills system. Injectate CO_2 has a $\delta^{18}O$ value of roughly –1 per mil.

Work Next Quarter

- Complete helium porosimetry and single PFT tracer flow experiments using Ottawa sand.
- Initiate helium porosimetry and single PFT tracer flow experiments using Frio material.
- Complete fluid and hydrocarbon chemical and isotopic analyses of Lost Hills samples.

Subtask B-3A: The Frio Pilot Test Monitoring with Introduced Tracers and Stable Isotopes

Goals

To provide tracer and stable isotope methods that will help quantify the fate and transport of CO_2 injected into the subsurface at the Frio, Texas site (Task E). The resulting data will be used to calibrate and validate predictive models used for (1) estimating CO_2 residence time, reservoir storage capacity, and storage mechanisms; (2) testing injection scenarios for process optimization; and (3) assessing the potential leakage of CO_2 from the reservoir.

Previous Main Achievement

- Preliminary mineralogical characterization of the Frio Formation sandstone sample was completed (in support of Task E).
- Preliminary gas chemistry and isotope analysis of CO_2 from the BP Hydrogen 1 plant, Texas City, Texas, was conducted in support of permitting documentation needed to inject CO_2 into the Frio formation (Task E).

Accomplishments This Quarter

- Provided appropriate material to facilitate permitting documents for the Frio Brine Pilot Project injection test (Task E).
- Extended collaborative opportunities and information exchange with Neeraj Gupta, Battelle Memorial Institute.

Progress This Quarter

Provided supporting documentation for NEPA review and permitting concerning PFTs. These materials included MSDS sheets for all tracers, injection rates, and quantities, and described types of samples desired for PFT analysis.

Extended collaborative opportunities and information exchange with Neeraj Gupta, Battelle Memorial Institute, including:

- Input on suggested isotopic analysis, including ^{18}O and H isotopes of brines, ^{13}C and S isotopes, and ^{87}Sr isotopes and chemical analysis, to consider in addition to major, minor, and trace-element chemistry, and pH.
- C, O, H, and noble gas chemistry as well as C, O, H, and dissolved organic species, such as carboxylic acids in solids and liquids recovered from the well.
- Background information and publications on the types of tracer regimes to consider during coring.

Work Next Quarter

- Attend the Frio CO_2 injection-planning meeting to be held in Houston in April.
- Provide expanded guidance on the sampling plan for introduced tracers and stable isotopes.

Task C: Enhance and Compare Simulations Models

Subtask C-1: Enhancement of Numerical Simulators for Greenhouse Gas Sequestration in Deep, Unmineable Coal Seams

Goals

To improve simulation models for capacity and performance assessment of CO_2 sequestration in deep, unmineable coal seams.

Previous Main Achievements

- Comparisons of the first two sets of simple numerical simulation problems in Part I with pure CO_2 injection and in Part II with flue gas injection have been completed. The participants are CMG's GEM, ARI's COMET3, CSIRO/TNO's SIMED II, BP's GCOMP and Imperial College's METSIM2. The results have been posted in the ARC's password protected website: http://www.arc.ab.ca/extranet/ecbm/.
- Field data obtained from two single-well micropilot tests with pure CO_2 and flue gas injection conducted by the Alberta Research Council (ARC) at the Fenn Big Valley site, Alberta, Canada, have been released to five participants (i.e., TNO, BP, CMG, ARI and Imperial College) for history matching (i.e., Problem Set 5). History matching provides an opportunity to validate new simulation-model developments in a realistic field situation.

Main Achievements This Quarter

- Comparisons for the Problem Sets 3 and 4 in Part III (which are more complex problems) have been completed, with participation from CMG's GEM, CSIRO/TNO's SIMED II, ARI's COMET3, GeoQuest's ECLIPSE, BP's GCOMP, and Imperial College's METSIM2.
- Initial history-matching results from CSIRO/TNO's SIMED II and Imperial College's METSIM2 have been collected for the field data obtained by the Alberta Research Council (ARC) at the Fenn Big Valley site, Alberta, Canada, and are being documented.

Progress This Quarter

Comparisons for Problem Sets 3 and 4 in Part III (which are more complex problems) have been completed. Problem Set 3 is the enhancement of Problem Set 2 (i.e., a 5-spot CO_2 injection/production process), taking into account the effect of gas desorption time (or gas diffusion) between the coal matrix and the natural fracture system. Participating models for Problem Set 3 are GEM, ECLIPSE, COMET2 SIMED II, and METSIM2. Problem Set 4 is the enhancement of Problem Set 2 (i.e., a 5-spot CO_2 injection/production process), taking into account the effect of natural fracture permeability as a function of natural fracture pressure. Participating models for Problem Set 4 are GEM, COMET2 SIMED II, GCOMP, and METSIM2. Comparison results in Part III will be presented at the 2nd Annual Conference on Carbon Sequestration, May 5–8, 2003, Alexandria, Virginia.

Initial history-matching results from CSIRO/TNO's SIMED II and Imperial College's METSIM2 for the field data obtained by the Alberta Research Council (ARC) at the Fenn Big Valley site, Alberta, Canada, have been collected and are being documented. **Figures 10 and 11** show history-matching results of well bottom-hole pressure and production gas composition, respectively, for a single-well micropilot test with pure CO_2 injection from METSIM2.

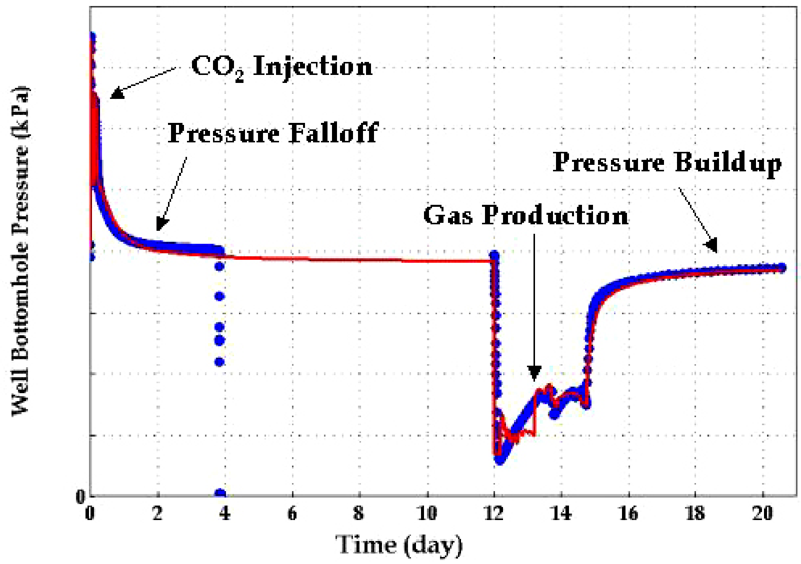

Figure 10. History match of well bottom-hole pressure for a single well micro-pilot test with pure CO_2 injection using SIMED II

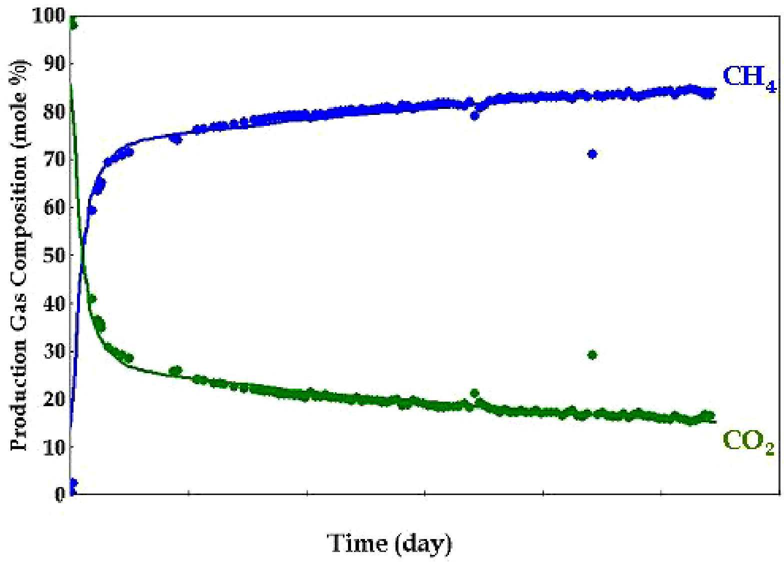

Figure 11. History match of production gas composition for a single well micro-pilot test with pure CO_2 injection using SIMED II

Work Next Quarter

ARC will continue to collect and document numerical results from potential new participants such as Shell's MoReS for problem sets in Parts I–III. These results will be posted in the ARC website, together with the published results from the previous participants.

Under an agreement between ARC and CMG, a new algorithm, developed by ARC to describe the permeability variation of coal during CO_2 and flue gas injection, has been incorporated into GEM. A history match of the ARC's field data using GEM with the new algorithm has been initiated.

ARC will continue to collect and document field history-match results from participants who have access to the field data.

Subtask C-2: Intercomparison of Reservoir Simulation Models for Oil, Gas, and Brine Formulations

Goals

To stimulate the development of models for predicting, optimizing, and verifying CO_2 sequestration in oil, gas, and brine formations. The approach involves: (1) developing a set of benchmark problems; (2) soliciting and obtaining solutions for these problems; (3) holding workshops that involve industrial, academic, and laboratory researchers; and (4) publishing results.

Previous Main Achievements

- A first workshop on the code intercomparison project was held at Berkeley Lab on October 29–30, 2001, with the initial modeling results by different groups showing reasonable agreement for most problems.
- Further simulations were performed for the intercomparison test problems. Write-ups for individual test problems were written and compiled.
- Comparisons of additional results from participating groups were made, and individual groups were contacted in an effort to reconcile certain differences.

Accomplishments This Quarter

- The final report on the code intercomparison study was completed, as well as a more detailed report with Berkeley Lab results on the saline aquifer test problems.
- Following an invitation from the conference organizers, a paper presented at the GHGT-6 conference in Kyoto was expanded and submitted for possible publication in the journal *Energy*.

Progress This Quarter

The final report of the project was completed, following internal technical review. A more detailed report on Berkeley Lab's solution to the saline aquifer test problems was also completed. Both reports are currently being printed.

Work Next Quarter

- None is planned; Subtask C-2 is completed.

Task D: Improve the Methodology and Information for Capacity Assessment

Goals

To improve the methodology and information available for assessing the capacity of oil, gas, brine, and unmineable coal formations; and to provide realistic and quantitative data for construction of computer simulations that will provide more reliable sequestration-capacity estimates.

Previous Main Achievements

- A new definition of formation capacity, incorporating intrinsic rock capacity, geometric capacity, formation heterogeneity, and rock porosity, was developed for use in assessing sequestration capacity.
- A significant number of modeling studies of the Frio Brine Pilot Experiment (Task E) was completed, assuming different CO_2 injection scenarios and geologic models.

Accomplishments This Quarter

- Developed a basin-scale conceptual model of geologic complexity for the Frio Brine Pilot Experiment site (Task E). Quantitative data to probabilistically and deterministically create a simulation for basin has been compiled.
- Extended the modeling studies of the post-injection period for the Frio Brine Pilot Experiment from one year to 100 years. As in previous studies, the choice of characteristic curves has a strong impact on CO_2 plume evolution.
- Began development of the well-test plan for pre-injection and during-injection pressure-transient testing for the Frio brine Pilot Experiment (Task E).

Progress This Quarter

Basin-scale models.

To scale up the detailed models that we have been creating for capacity assessment, we need to develop regional models. A completely 3-D deterministic model would be prohibitively expensive to build at basin scale for this very heterogeneous and complex system, and model cell limitations would likely result in over generalizing controlling parameters. We therefore have developed a methodology to develop 2-D (or thin 3-D) models that retain the critical parameters controlling capacity.

Using this method, we collected data from Geomap structural maps for the upper Gulf Coast. We divided the top Frio structure into “drainage basins” under conditions of buoyant flow. We digitized the outlines of these drainage basins and the area of structural closure on the structural trap within the drainage basins. We also measured the throw-on faults that compartmentalize the region. Areas with likely higher-than-background risk of leakage, including oil fields characterized by closely spaced wells and highly complex zones around salt domes, were also digitized. From this database, we can create a probabilistic model for the geologic features that CO_2 would encounter when it is released from a well at any location. The database can also be used in a deterministic sense to assess capacity of the subsurface from a given location. **Figure 12** shows CO_2 being released at a well, traveling across a drainage basin to accumulate in a structural trap, exceeding the storage capacity of that trap, and spilling into the next basin (where it repeats the process). Capacity can be calculated by summing the trapping mechanisms along this flow path, which include CO_2 trapped by capillary processes as residual saturation, dissolved CO_2, and CO_2 trapped in structural traps.

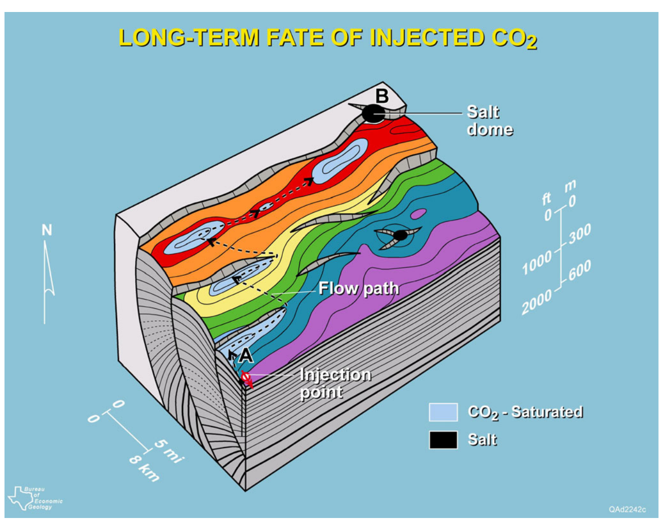

Figure 12. Long-term fate of injected CO_2 (see text for details)

Long-term Modeling.

New modeling studies of the South Liberty field, location of the Frio Brine Pilot Experiment, were conducted. (Earlier pilot-site modeling studies are described in the four previous quarterly reports.) The present studies consider CO_2 injection into the C sand, which is 12 m thick and lies at a depth of about 1,500 m, using the same "Version 0" model described previously. A perspective view and plan view of the model are shown in **Figure 13.**

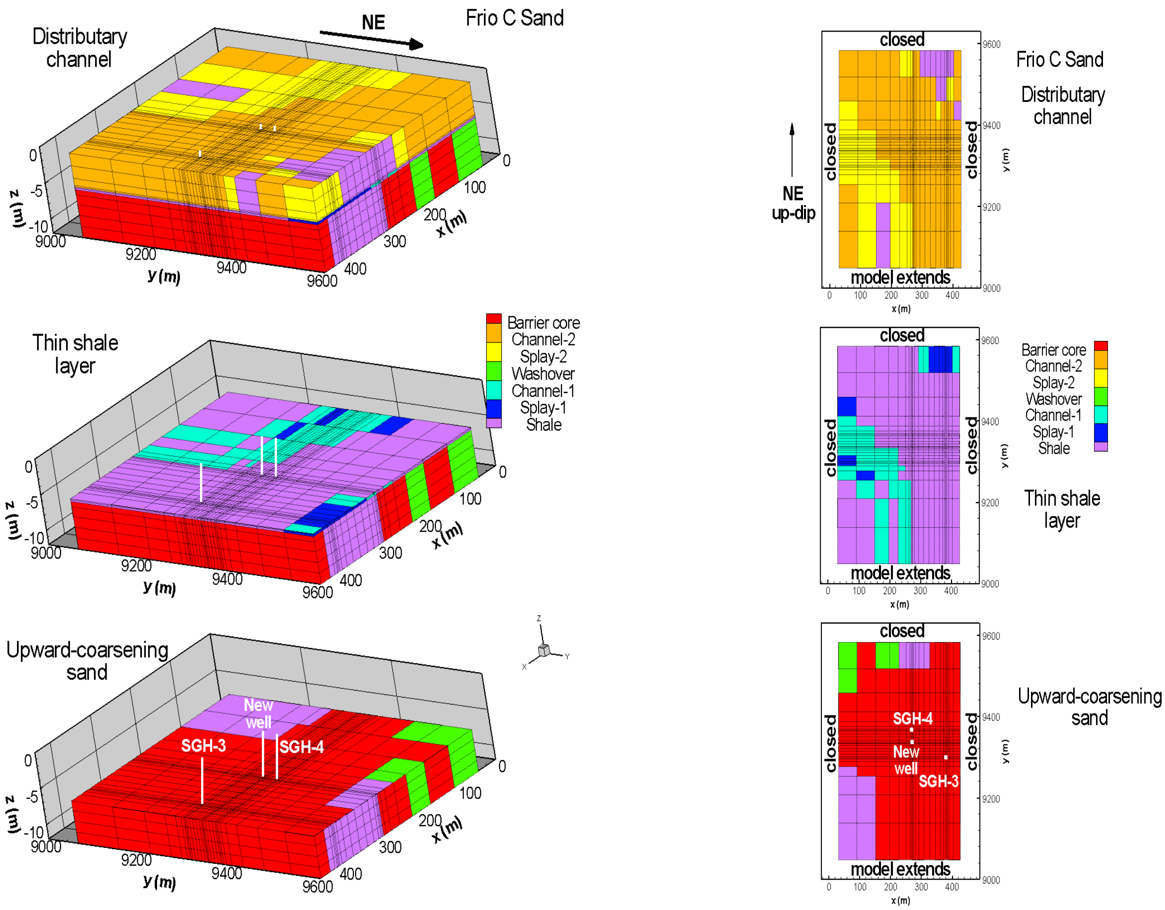

Figure 13. The Version 0 model of the Frio C sand showing a perspective view and plan view of each depositional setting. Permeability decreases with color from red to violet.

Injection of supercritical CO_2 into the new well (**Figure 13**) was modeled assuming a rate of 250 T/d (2.89 kg/s) for a period of 20 days. The injection interval is the 6 m thick sand beneath the thin shale layer shown in **Figure 13**. Two cases are considered. One case uses generic characteristic curves in which the relative permeability function has a residual gas saturation $S_{gr} = 0.05$. The other case uses a relative-permeability function with $S_{gr} = 0.30$, believed to be typical of the Frio sands. In the previous quarterly report, we showed snapshots of the injected CO_2 plume during the 20-day injection period and for up to one year afterward. In **Figures 14–17**, we show 100 years of evolution of the CO_2 plume for the generic and Frio-like characteristic curves.

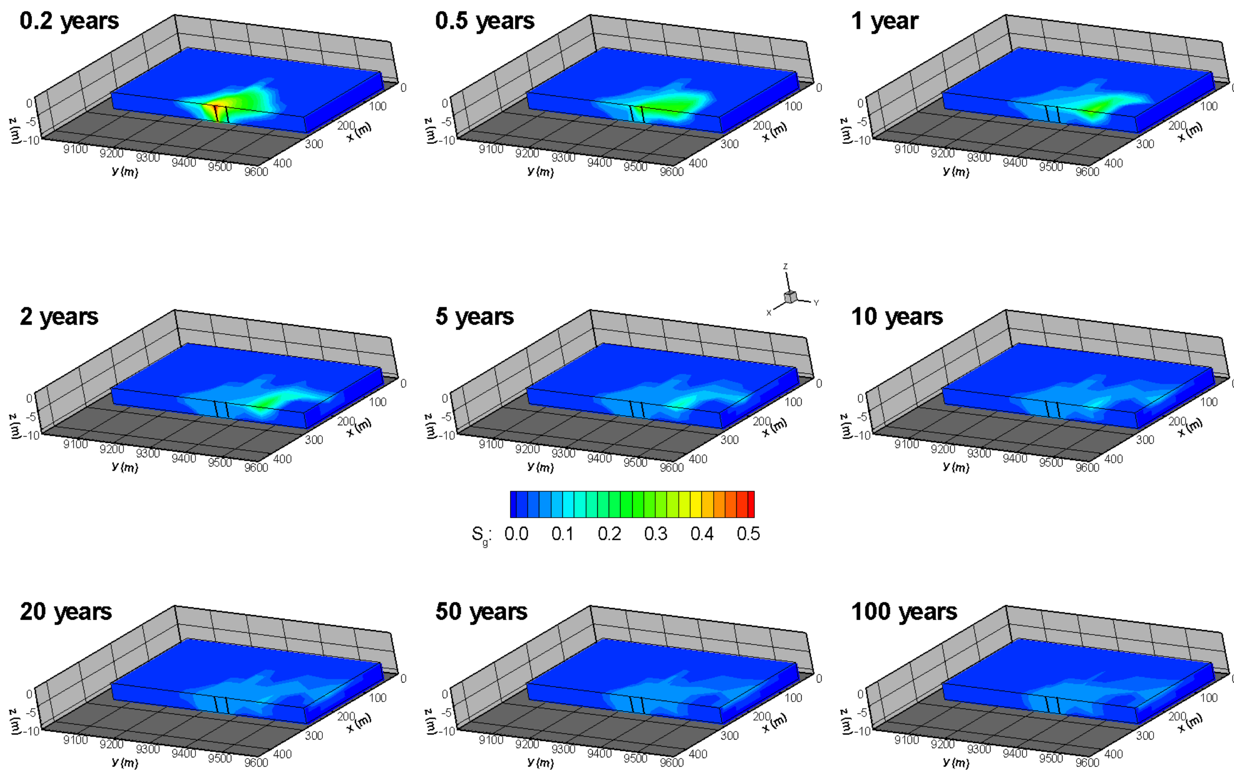

Figure 14. Snapshots of CO_2 in the immiscible gas-like phase, for long times after the 20-day injection period, using generic characteristic curves with S_{gr} = 0.05.

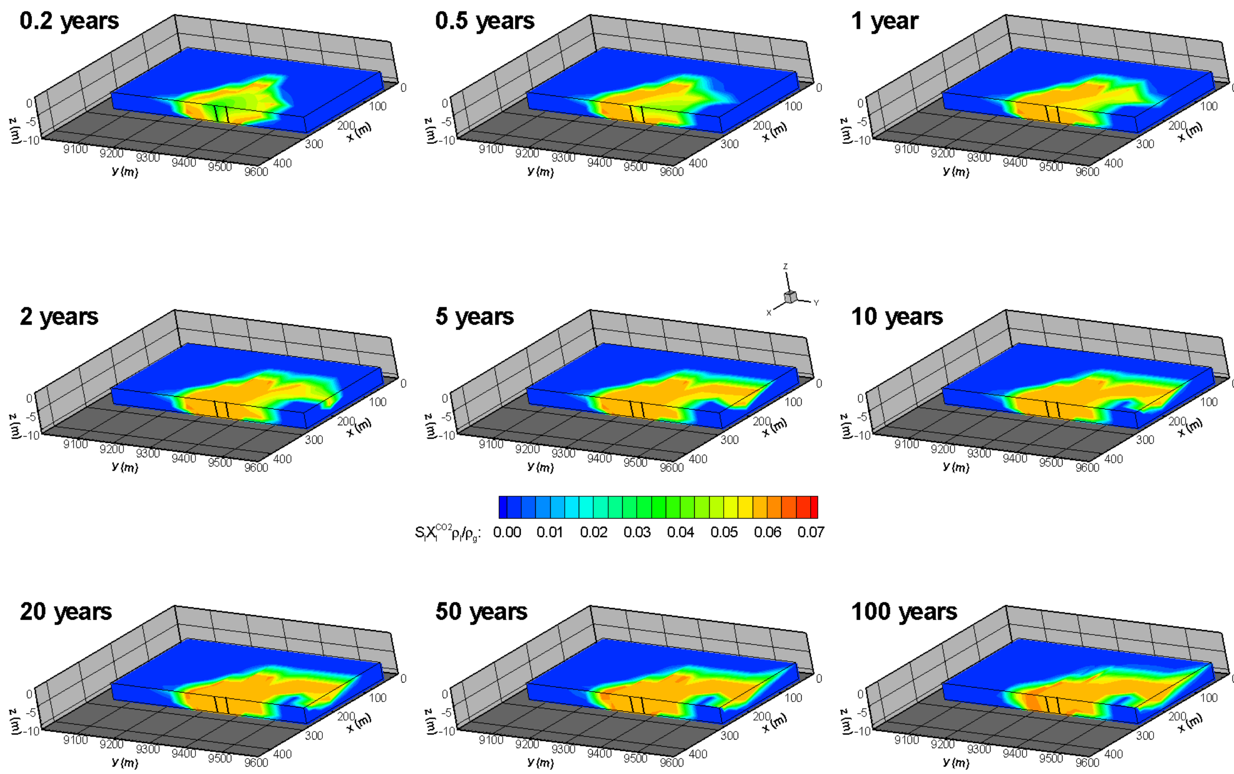

Figure 15. Snapshots of the plume of CO_2 dissolved in the aqueous phase, for long times after the 20-day injection period, using generic characteristic curves with S_{gr} = 0.05. Note that different color scales are used for **Figures 14 and 15.**

For both characteristic curves, the injected CO_2 partitions primarily into an immiscible gas-like phase that, although heavy and viscous compared to atmospheric CO_2, is much lighter and less viscous than the surrounding brine (**Figures 13 and 16**). A small but significant fraction of the CO_2 (about 10–15%) dissolves in the aqueous phase as well (**Figures 15 and 17)**

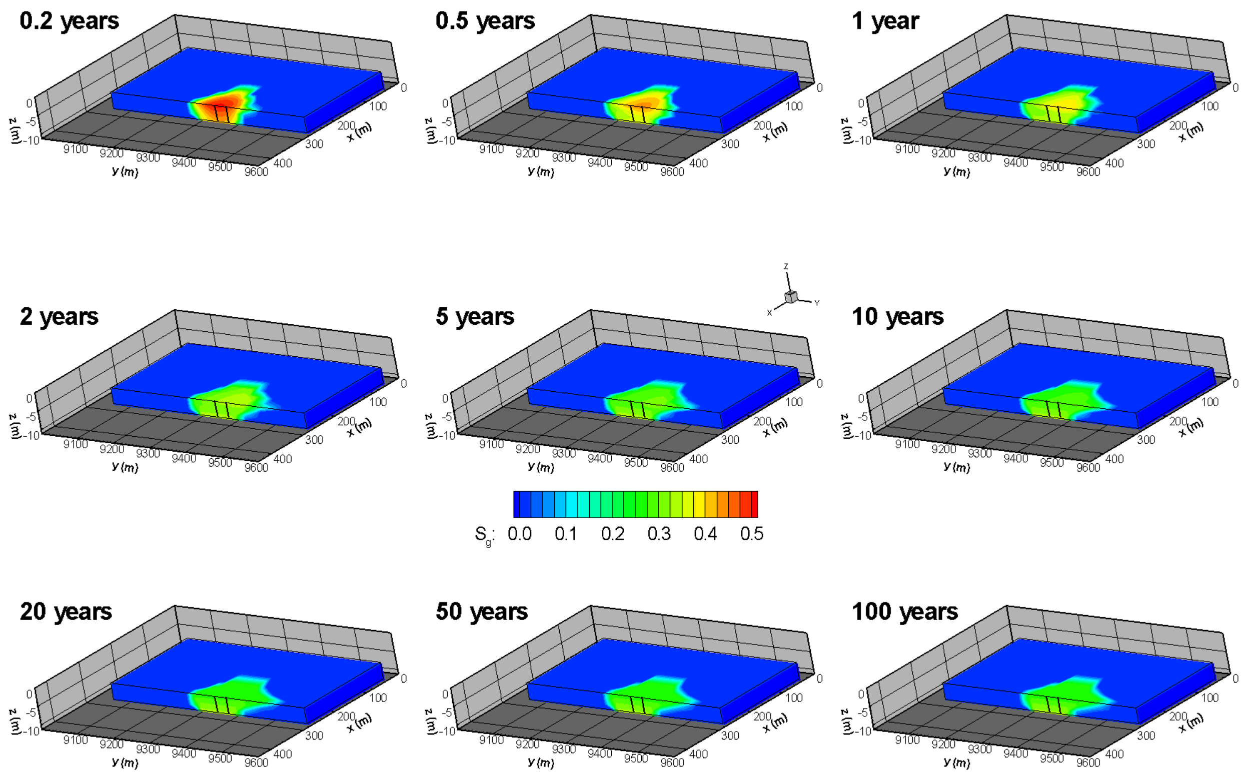

Figure 16. Snapshots of CO_2 in the immiscible gas-like phase, for long times after the 20-day injection period, using Frio-like characteristic curves with S_{gr} = 0.30.

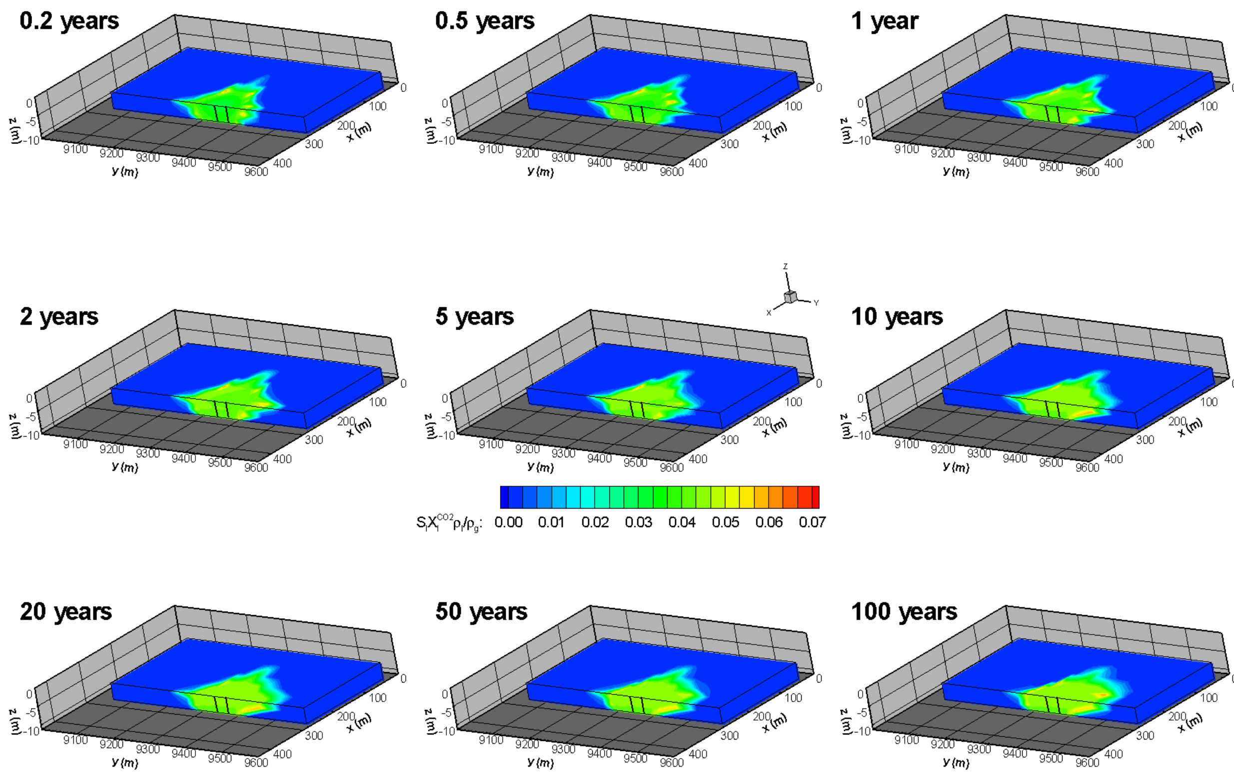

Figure 17. Snapshots of the plume of CO_2 dissolved in the aqueous phase, for long times after the 20-day injection period, using Frio-like characteristic curves with S_{gr} = 0.30. Note that different color scales are used for **Figures 16 and 17**.

Henry's Law controls the phase partitioning, so as long as any gas-like phase remains at a given location, the amount of dissolved CO_2 remains constant. Thus, the dissolved CO_2 plume indicates not only where the gas-like CO_2 is at a given time, but where it has been throughout its evolution. For the generic characteristic curves **(Figures 14 and 15)**, the low residual gas saturation allows extensive up-dip movement of the gas-like CO_2 plume, accompanied by significant decreases in gas saturation as the plume spreads. At long times, the proportions of immiscible and dissolved CO_2 are comparable. In contrast, for the Frio-like characteristic curves (**Figures 16 and 17**), the high residual gas saturation precludes extensive movement or dilution of the gas-like CO_2 plume, and the proportion of dissolved CO_2 remains about 10–15% for the entire simulated period of 100 years.

Well test plan.

Pressure-transient monitoring will play an important role in both site characterization and CO_2 plume monitoring for the upcoming Frio Brine Pilot Experiment. Pre-injection site characterization goals include estimation of single-phase flow properties, determination of appropriate lateral boundary conditions for the subvertical faults bounding the pilot site, assessment of the integrity of intersand shale layers, and analysis of ambient phase conditions within the formation (although nominally brine-saturated, the pilot-site sands may harbor immobile gas-phase or dissolved hydrocarbons). Pressure-transient monitoring during CO_2 injection will enable estimation of two-phase flow properties and help track the movement of the injected CO_2 plume.

Two wells will be available for well testing: well SGH-4 and the new well to be drilled 30 m down dip from Well SGH-4 (see **Figure 13**). The primary open interval for injection, production, and monitoring will be the C sand, but we hope to be able to additionally monitor the B sand interval from at least one well during at least some of the well tests.

Table 1 shows the sequence of well tests proposed to occur prior to CO_2 injection. The primary motivation for these tests is site characterization. Short-term (few days) well tests are designed to improve our understanding of the *in situ* composition and phase conditions for the nominally brine-saturated sands of the upper Frio. Generally, single-phase liquid systems have much smaller compressibility than do two-phase systems, so whether or not a small gas phase (methane) is present will have a large effect on the propagation of pressure signals. **Figure 18** shows an example, comparing pressure responses at the pumping well for simple radial models of formations with no gas, 5% gas saturation, and 10% gas saturation. For each gas content, two outer boundary conditions are considered: an infinite model and a model with a closed boundary at a radial distance of 250 m. It is apparent that the addition of gas greatly delays the time at which the pressure signal arrives at the location of the closed boundary.

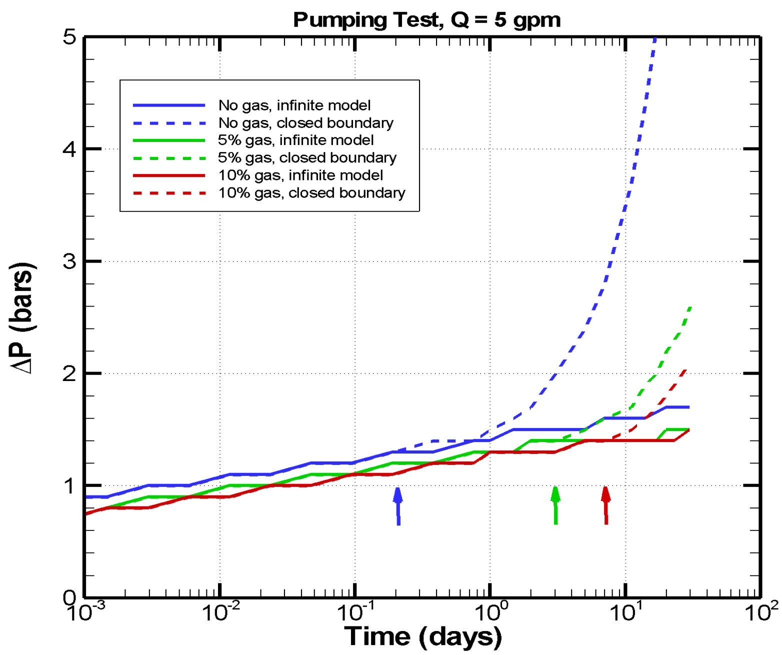

Figure 18. Pressure transients for infinite radial models and models with closed outer boundaries, for three gas saturations. The arrows identify the times at which the closed boundary is felt.

Furthermore, if dissolved gas is present in the aqueous phase, it may exsolve during the pressure decline accompanying pumping. The presence of a separate gas phase will then increase the compressibility of the system, resulting in pressure pulses that show a change in behavior at the time of exsolution. Conversely, if a small amount of gas is present initially in a separate gas phase, injection may increase pressure enough to dissolve it, decreasing compressibility.

The long-term test (two weeks) is designed to provide information on the flow properties of the formation and the lateral boundaries of the fault block in which the wells are located. It will also provide information on the role of smaller faults within the fault block. In addition, if monitoring proves feasible in both the B and C sands, an assessment of their connectivity can be made. Two possible mechanisms have been hypothesized to connect the B and C sands. This first possibility is simply the presence of gaps in the shale layer separating the two sands. The second possibility is that, with flow possibly occurring readily across the intra-fault-block faults, one of these faults in the vicinity of well SGH-4 would show sufficient offset to juxtapose the B and C sands. In theory, the relative timings of the pressure responses in the B and C sands may allow us to distinguish between these two possibilities.

Table 1. Well testing prior to CO_2 injection

Activity	Purpose	Duration
None	Recovery period after completion of new well and workover of Well SGH-4; allow pressures and temperatures to return to undisturbed conditions	1–2 weeks
Pump Test 1 Well SGH-4 C sand at 50 gpm	Decrease pressure around the well; look for evidence of exsolution of dissolved gas in P vs. t. Save water for subsequent injection test	1–2 days
Injection Test 1 New well C sand at 50 gpm	Increase pressure around the well; look for evidence of dissolution of gas in P vs. t	1–2 days
Pump Test 2 New well C sand at 50 gpm	Same as Pump Test 1. Compare responses of two wells	1–2 days
Injection Test 2 Well SGH-4 C sand at 50 gpm	Same as Injection Test 1. Compare responses of two wells	1–2 days
None	Pressure recovery	2 weeks
Pump Test 3 New well C sand at 5 gpm	Estimate kH, investigate boundary effects; save water for possible CO_2 chaser	2 weeks
None	Pressure recovery	4 weeks

Table 2 shows the proposed CO_2 injection schedule, which includes continuous pressure-transient monitoring in both the new injection well and in monitoring well SGH-4 during CO_2 injection. The discontinuous injection of CO_2 serves two purposes. First, the rest periods enable downhole geophysical surveys to be conducted. Second, the resumption of CO_2 injection after pressures have recovered during the rest period provides an opportunity to examine early-time pressure transients within a two-phase flow system. As noted above, two-phase fluids have much larger compressibility than do single-phase liquids, thus greatly slowing pressure responses, enabling subtle effects to be observed much more readily.

Table 2. Pressure-transient monitoring during CO_2 injection (assumes 3,750 T of CO_2 to be injected)

Activity	Purpose	Duration
Inject CO_2 at 250 T/day	Create a plume that does not reach monitoring well; pressure-transients reflect single-phase liquid conditions	1 day
Rest	Allow pressure recovery, opportunity for geophysics	2 days
Inject CO_2 at 250 T/day	Create a plume that may reach monitoring well (or not); pressure-transients reflect two-phase conditions	3 days
Rest	Allow pressure recovery, opportunity for geophysics	5 days
Inject CO_2 at 250 T/day	Create a bigger plume – try to make sure it reaches the monitoring well	11 days
Rest	Allow pressure recovery, opportunity for geophysics	2 days
Inject formation brine at 50 gpm	If CO_2 has not reached monitoring well, try to get it there; if it has, study behavior of trailing edge of plume	2 weeks

Work Next Quarter

- Basin-scale data will be organized for input into numerical models and reporting. Outreach materials that have been developed will be finalized.
- Further modeling studies will continue on two fronts:
- Capacity investigations using generic models designed to capture essential features of formations suitable for sequestration.

- Simulations of the planned Frio Brine Pilot Experiment to be conducted at the South Liberty field. A near-term focus will be forward and inverse modeling of the well-test program to be conducted prior to CO_2 injection, to optimally design the well tests. As more specific site characterization information becomes available, it will be incorporated into simulations of CO_2 injection.

Task E: Frio Brine Pilot Project

Goals

To perform numerical simulations and conduct field experiments at the Frio Brine Pilot site, near Houston, Texas, that:

- Demonstrate that CO_2 can be injected into a saline formation without adverse health, safety, or environmental effects.
- Determine the subsurface location and distribution of the cloud of injected CO_2.
- Demonstrate understanding of conceptual models.
- Develop the experience necessary for the success of large-scale CO_2 injection experiments.

Note: This task does not include work being done by the Texas Bureau of Economic Geology under the project “Optimal Geological Environments for Carbon Dioxide Disposal in Brine Formations (Saline Aquifers) in the United States,” funded under a separate contract.

Previous Main Achievements

- A planning workshop was held at BEG (Austin, Texas) on July 8–9, 2002, to explore the interrelationships among the modeling and monitoring techniques proposed by the GEO-SEQ team for conducting the Frio Brine Pilot Experiment. A time line and a more detailed plan for implementation of modeling and monitoring techniques were developed.
- A proposal to construct a new injection well instead of retrofitting a 50-year-old oil well was prepared. The new well would be closer to the monitoring well and directly down dip. Less CO_2 and a shorter injection period will be required to achieve breakthrough in the monitoring well.

Accomplishments This Quarter

- Permit preparation for the project has been completed with substantive input from the GEO-SEQ team.
- More detailed plans have been created to integrate the various GEO-SEQ experiments and studies—see previous tasks—with the well design and test schedule.

Progress This Quarter

BEG and Sandia Technologies (subcontractor) have completed the Environmental Assessment for the Frio pilot project with a substantive contribution by the GEOSEQ team. Detailed well-test plans have been completed, integrating water and CO_2 injection, crosswell and Vertical Seismic Profile(VSP) and wireline logging and sample collection in the injection and monitoring wells. On February 7, representatives of Task E met in Austin, Texas, with Schlumberger Research staff to integrate them into the project. We have invited NETL staff members Duane Smith, Art Wells, Curt White, and Rod Diehl to participate in monitoring and observation activities during the experiment.

Work Next Quarter

Next quarter, we will complete the report to support the Class 5 permit application to the Texas Commission on Environmental Quality. We plan to meet at the Bureau’s Houston Core Research facility to plan for using the facility as a staging area and visit the field site. Baseline monitoring will begin. We will continue work with stakeholders in the Houston area to prepare for public hearings to be held this quarter.